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Bidirectional linkage between a long-term energy system and a short-term power market model

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ABSTRACT

This paper proposes a novel bidirectional linkage between a long-term energy system model and an operational power market model. This combined modelling framework provides long-term energy system investment strategies that explicitly consider the operational complexity of the power sector. The linkage is demonstrated using an energy system model of Norway and a European power market model with a specific high detail level of hydropower operation. For Norway, with its hydropower-dominated electricity sector, the linkage is designed to improve the modelling of hydropower generation and external electricity markets in the energy system model, and to provide consistent assumptions concerning Norwegian electricity demand and capacity in the power market model. The difference in income of hydropower producers, which is endogenous in both models, is used as a convergence criterion. The linkage is tested for various future developments of the European power market and is successful for three of the four analysed instances. However, when the linkage is evaluated in a system with a very high share of intermittent electricity generation and large variations in electricity price, it fails to converge on hydropower income. This is because the simulated Norwegian electricity prices differ significantly between the two models in this situation.

1. Introduction

Energy system and power market models are tools that are used to understand the complexity of the future energy system. An **energy system model** is a long-term model with investments in and operation of the energy system to meet the future energy service demand, whereas a **power market model** is an operational model of the power sector with a high level of detail. This paper presents a novel methodology that utilises the strength of both these types of models through a bidirectional linkage. The advantage of this combined modelling framework is that it gives long-term energy system investment strategies that explicitly consider the operational complexity of the power sector. The analysis in this paper demonstrates that the bidirectional linkage provides a better representation of the coupling between the power sector and other parts of the energy system when the linkage converges and thereby improves the quality of the insights provided from both the energy system and power market models.

The linking methodology is demonstrated with the **EMPS** power market model [1] and the **TIMES-Norway** energy system model [2] in analysis of the Norwegian energy system towards 2050. Norway has the largest hydropower generation and reservoir capacity in Europe, with a reservoir capacity of 84 TWh [3] and a hydropower share of 96% of the electricity generation mix in 2016 [4]. The linkage is to design a modelling framework that improves the representation of the hydropower-dominated electricity sector in TIMES-Norway and provides consistent model input on Norwegian electricity capacity and consumption to EMPS. EMPS is a well-established operational model of electricity markets with a detailed representation of the Nordic hydropower system and geographical coverage of all European countries. The model is e.g. used for hydropower scheduling, electricity price forecasting and to analyse impacts on power system operations. To exemplify, EMPS is applied in [5] to study the role of Norwegian hydropower in a highly renewable European power market, in [6] to analyse the impact of large-scale wind power integration on European day-ahead markets, in [7] to assess the strategic use of hydropower in

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a scenario with high wind power integration and in [8] to provide operational details of the Northern European power market in transmission capacity planning. TIMES-Norway is widely used to analyse the cost-optimal development of the Norwegian energy system towards 2050 for various assumption on e.g. future policies, demand projections and technology developments. For example, the model is used in [9] to analyse the energy system effect of the EU renewable energy directive, in [10] to study the impact of the green certificate market for different grid and hydropower capacity expansion scenarios, in [11] to demonstrate how the evolvement of demand for energy services influences investments in renewable energy and in [12] to address the welfare cost of a non-coordinated development of wind power and electricity grid expansion.

1.1. Research motivation

Due to the long-time horizon and the wide sectoral coverage, simplified modelling of parts of the energy system is often required to achieve a computationally tractable energy system model. However, an energy system model with a coarse description of parts of the energy system can omit details that have a significant impact on the model results. With more renewables in the electricity generation mix, there has been an increased focus on how to handle the power sector in energy system models. According to [13], a simplified modelling of the power sector presents challenges related to the representation of intermittent renewables in an energy system model and can provide misleading results with regard to flexibility requirements. Further [14], conclude that no current energy system model has the necessary level of detail for the power sector, including a sufficient temporal resolution, to represent the constraints related to the integration of intermittent electricity generation. Moreover, the impact of different temporal resolutions and modelling methods designed to include high penetration of renewables in energy system models is demonstrated in [15]. Their study shows that a simplified method of balancing electricity supply and demand overestimates renewable energy integration capacity in the system by up to 9% and can therefore underestimate the necessary installed electricity generation capacity or storage capacity.

A power market model often provides the operation of each of the individual generation units in the power sector, whereas an energy system model tends to provide operation according to technology type [14]. Furthermore, the majority of power market models have a higher temporal resolution than energy system models [13] and can include specifications such as ramping times, start-up costs and minimum up time [14].

Explicit modelling of weather-dependent short-term uncertainty enabling valuation of flexibility, e.g. by use of stochastic programming [16], is state of the art in power market models, such as unit commitment problems [17]. This is not as widespread in long-term energy system models, there being just a few examples of models considering short-term uncertainty of intermittent electricity generation and demand. These examples include [18] that demonstrates the impact of policy actions and energy prices on the cost-optimal development of the energy system in Norway and Sweden [19], that study the impact of zero energy buildings in the Scandinavian energy system and [20] that analyse low-carbon transition at the Svalbard island. The motivation behind a stochastic approach is that a deterministic approach that considers one operational situation only, can provide sub-optimal investments. A conclusion of [21] is that ignoring short-term uncertainties undervalues the need for operational flexibility and can give insufficient investments. This conclusion is supported by [22] that show that intermittent renewables are considerably overvalued, flexible energy technologies are underestimated and that the total system cost is significantly underestimated in deterministic electricity models.

A major challenge when using power market models for long-term analysis is to provide a consistent model input for installed capacities, fuel prices and electricity consumption. When considering a power sector in transition, with increasing shares of intermittent renewables and more electrification, it can be misleading to base the model input on the current characteristics of the power sector. For example, with more electricity used in end-use sectors, in the form of more heat pumps and electric vehicles (EVs), for example, the future hourly electricity consumption profile will change [23]. Further, more sources of flexibility, such as demand response or storage, will also influence the electricity consumption profile [24]. A main conclusion of [25] is that new approaches are needed to generate electricity consumption profiles for power market models, such as EMPS, that are used for long-term analysis. This paper identifies three possible directions to incorporate the future use of energy efficiency, new technologies and local flexibility sources in long-term electricity consumption profiles: sectoral forecasting of end use, a bottom-up approach and soft-linking with energy system models.

Energy system models can provide a consistent set of model parameters to power market models, since electricity consumption and electricity generation capacities are model outputs. However, endogenous electricity consumption and generation capacities from an energy system model are often based on a simplified representation of the power sector. In this context, a bidirectional linkage can facilitate the incorporation of the power sector to the energy system model with a high level of detail.

1.2. Literature review on linking energy system and power market models

The linking of models in the literature can be split into unidirectional and bidirectional linkage. For **unidirectional linkage**, a set of model decisions from the energy system model are used as an input to the power market model, with no feedback to the energy system model. For **bidirectional linkage**, model decisions from the power market model are also transferred to the energy system model in an alternating setup in which the two models systematically modify each other. The iteration between the two models is executed until the two models converge.

A method for unidirectional linkage was first introduced in [26] and has been used in several other studies. The principle of the methodology is to test the performance of the electricity generation capacity and electricity consumption from the energy system model in the power market model for a given model period. The paper links a PLEXOS power market model to evaluate the appropriateness of the electric power generation portfolio developed by the Irish TIMES model and to consider whether it is technically feasible. The power market model has higher temporal resolution compared to the TIMES model and includes integer properties like ramping, start-up costs and minimum up time that is neglected in the Irish TIMES model. The conclusion of this linking is that the Irish energy system model provides a reliable power system but undervalues flexible elements and underestimates wind curtailment. Further, a linkage of a MARKAL energy system model and a power market model of the Netherlands, that is based on the methodology presented in [26], is demonstrated in[27]. Their results show that the energy system model is insufficient to capture the required investments needs in a future with a high share of renewables. The same unidirectional linkage methodology is used in [28] but has a different focus, where linking a TIMES energy system model and a power market model of Belgium is used to identify the optimal temporal resolution and modelling of operational power market constraints in the TIMES model.

A weakness of a unidirectional linkage is that the insights from the power market model do not directly improve the results of the energy system model. Thus, a unidirectional linkage is designed to verify the feasibility of the model decisions from the energy system model and is not used to improve the quality of the results. For example, a unidirectional linkage does not capture whether the investments in an energy system model should be modified due to operational constraints in the power sector.

To the authors knowledge, the use of a bidirectional linkage of an energy system and a power market model is limited to three studies. A common feature of these studies is that they exclude either electricity supply or end-use sectors in the energy system model. This implies that these studies do not utilise the full strength of the energy system model with endogenous competition and interplay between various energy carriers and technologies across sectors.

The first study [29], omits investments in electricity generation capacity in the TIMES-Norway energy system model in a bidirectional linkage with the EMPS power market model. In the energy system model, the Norwegian electricity sector is only represented by an exogenous set of electricity prices, and there are no endogenous investments in new power plants whereas the electricity consumption is endogenous. In the linkage, the electricity consumption from the energy system model is used as an input to the power market model. Thereafter, the endogenous electricity prices from the power market model are used as an input to the energy system model. The iterations between the two models are continued until the differences in the electricity prices from the power market model and the electricity consumption in the energy system model are only marginally changed for a given iteration compared to the previous iteration. Consequently, the convergence of the linkage is measured using the same parameters that are exchanged between the models.

The second study [30], includes only the German electricity generation, transmission and demand in the energy system model PERSEUS and excludes end-use sectors, such as buildings, transport and industry, in the bidirectional linkage with the power market model AEOLIUS. This implies that electricity consumption is a model input in both models. In the linking procedure, the electricity generation capacity from the energy system model is an input to the power market model. Based on the performance of this capacity mix in the power market model, constraints on the relationship between intermittent and flexible capacity are added in the energy system model. The description of the linking methodology is vague, and it is not clear how the constraints and convergence criterion are designed.

Similar to [30], the third study [31], includes only the power sector of Portugal in a TIMES energy system model in the linkage with the EnergyPLAN power market model. In the linking, the electricity generation capacity from the energy system model is used as an input to the power market model. The convergence criteria used is as follows: if the electricity generation from intermittent renewable capacity reaches 90% of the annual power output in the power market model relative to the energy system model, the solution is satisfactory. Otherwise, a limit on the maximum renewable capacity is included in the energy system model based on the performance of the power market model.

As opposed to previous bidirectional linking methodology, the proposed linking strategy of this paper does not exclude parts of the energy system in TIMES-Norway. This is to ensure that the evolution of the entire energy system, including investments and operation of energy supply, distribution and demand, considers the operational details of the power sector. This paper also aims to present a transparent linking methodology with a clearly defined convergence criterion.

1.2.1. *Paper structure*

The remainder of this paper is structured as follows: Section 2 elaborates on the models and linking methodology used in the paper. Section 3 presents the model results from the linked models, and Section 4 concludes and discusses the value of using a bidirectional linkage between an energy system and a power market model.

2. Methodology

In this section, the EMPS power market model and the TIMES-Norway energy system model are described and the differences between these two models are addressed. Thereafter, a novel linking strategy is proposed, including a description of the parameters that are exchanged between the models and the convergence criteria.

2.1. *Power market model*

EMPS maximises the expected socioeconomic welfare in a hydrothermal power system by optimising the dispatch of generation and transmission capacity. The model fulfils a given electricity consumption profile with uncertainty regarding weather-dependent hydro inflow, wind and solar electricity generation, and temperature-dependent electricity consumption. A strength of the model is the detailed modelling of hydropower and operation of systems with energy storage, which includes cascaded hydropower systems with numerous reservoirs and power plants. The uncertainty in weather parameters is represented by a significant variation in inflow, wind, solar and temperature conditions from historical weather years affecting electricity generation and consumption. This is illustrated in Fig. 1, which shows the weekly inflow to Norwegian hydro reservoirs for 30 weather years from 1981 to 2010, where, for example, the energy inflow in week 23 ranges from 338 GWh to 1769 GWh.

The hydro dispatch problem is solved in two phases. First, in the strategy phase, stochastic dynamic programming is used to calculate water values with uncertainty in weather parameters described by several historical weather years. The water values represent the alternative costs of using water instead of storing it, giving the expected marginal cost of water, and are calculated on a weekly basis for one aggregated plant and reservoir per node. Secondly, the operation of the system is simulated for all the different weather years, finding optimal dispatch in each time step per node. Optimal dispatch is first found for an aggregated hydropower plant and reservoir per node, using the calculated water values for the current state of the system, thereby considering the weather uncertainty in the disposal of water. Then the optimal generation of the aggregated hydropower plants is heuristically distributed to the individual plants to consider the detailed hydropower system, as illustrated in Fig. 2. The heuristic approach determining the dispatch of the individual hydropower plants was developed for a power market with limited of intermittent generation. According to [32], a more formal optimisation of the plant dispatch is beneficial for analysing future energy systems with more intermittent generation. The aforementioned paper demonstrates that a formal optimisation of dispatch improves the representation of the flexibility in the hydro system and thereby lowers both the peak and the variations in the electricity prices compared to using the heuristic approach of EMPS.

In this study, the model uses a minimum of 30 historical weather years as input and the simulated results give optimal operation for all these weather years. In this paper, a simulated year

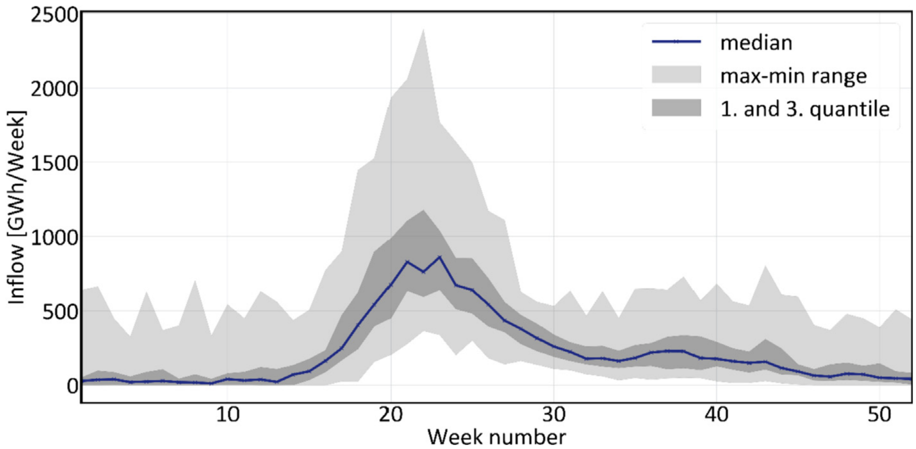

Fig. 1. Illustration of weekly hydropower inflow to water reservoirs for 30 weather Years.

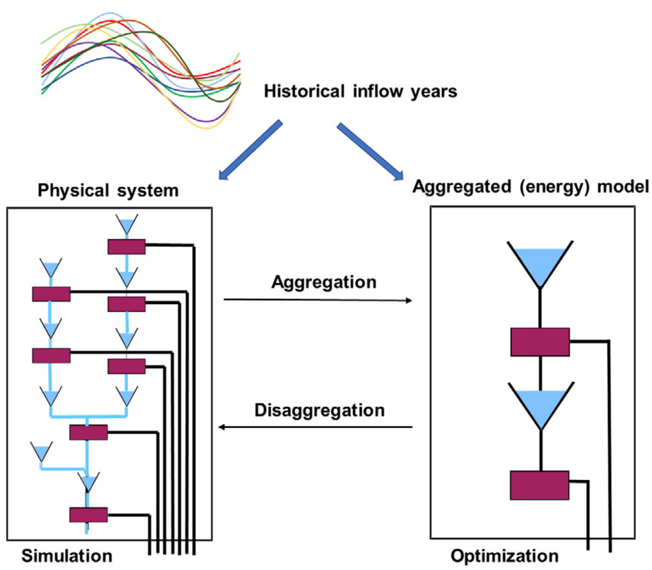

Fig. 2. Illustration of the hydro dispatch optimisation of the EMPS model.

in EMPS is split into 3744 sub-annual time-slices with 2-h resolution for weekdays and 4 h for weekends. Most of Europe is included in the spatial scope with the spatial resolution differing between the European countries covered (see Fig. 3). Note that Norway and the Nordic countries are modelled with more nodes than other European countries, with 11 nodes in Norway. The main inputs to the model include electricity consumption; generation and transmission capacities; fuel and CO_2 costs; technology characteristics like efficiencies and physical limitations; and historical weather data like temperatures, inflow and generation from renewables. Electricity consumption is divided among a fixed share, a temperature-dependent share, and interruptible consumption with a load-shedding cost. Electricity generation from wind and PV are based on hourly generation values for each node. The main outputs of the model include the operation of the power plants, electricity trade between nodes and corresponding marginal costs of electricity.

2.2. Energy system model

TIMES-Norway is an optimisation model of the Norwegian energy system that is generated by TIMES (The Integrated MARKAL-EFOM System) modelling framework [33]. TIMES is a bottom-up framework that provides a detailed techno-economic description of resources, energy carriers, conversion technologies and energy demand. It is mainly used for medium- and long-term analysis on the global, national and regional levels, including the Energy Technology Perspective [34]. TIMES models minimize the total discounted cost of a given energy system to meet the demand for energy services for the regions over the period analysed. The total energy system cost includes investment costs in both supply and demand technologies, operation and maintenance costs, and income from electricity export to and costs of electricity import from countries outside Norway.

TIMES-Norway is a technology-rich model of the Norwegian onshore energy system divided into five regions corresponding to the current electricity market spot price areas. An illustration of the price areas, with corresponding hydropower generation and reservoir capacity, are illustrated in Fig. 4. The model provides operational and investment decisions from the starting year, 2015, towards 2050, with six model periods within this model horizon. To capture operational variations in energy generation and end-use, each model period is divided into 260 sub-annual time slices, where each week is represented by five weekly time periods. This paper uses a traditional deterministic modelling approach, where the electricity generation and end-use demand are represented by one operational situation for each time-slice. The model has a detailed description of end-use of energy, and the demand for energy services is divided into 400 end-use categories within industry, buildings and transport. Note that energy services refer to the services provided by consuming a fuel and not the fuel consumption itself. For example, the heating demand in buildings is an energy service while the fuel used to heat the building is not. Each energy service demand category can be met by existing and new technologies using different energy carriers such as electricity, bio energy, district heating, hydrogen and fossil fuels. Other input data include fuel prices; electricity prices in countries with transmission capacity to Norway; renewable resources; and technology characteristics such as costs, efficiencies, and lifetime and learning curves.

2.3. Model comparison

An essential difference between EMPS and TIMES-Norway is the sectoral coverage of the energy system: TIMES-Norway covers all supply and demand sectors of the energy system whereas EMPS is limited to the power sector. Another difference between the models is the planning horizon: TIMES-Norway provides investments and

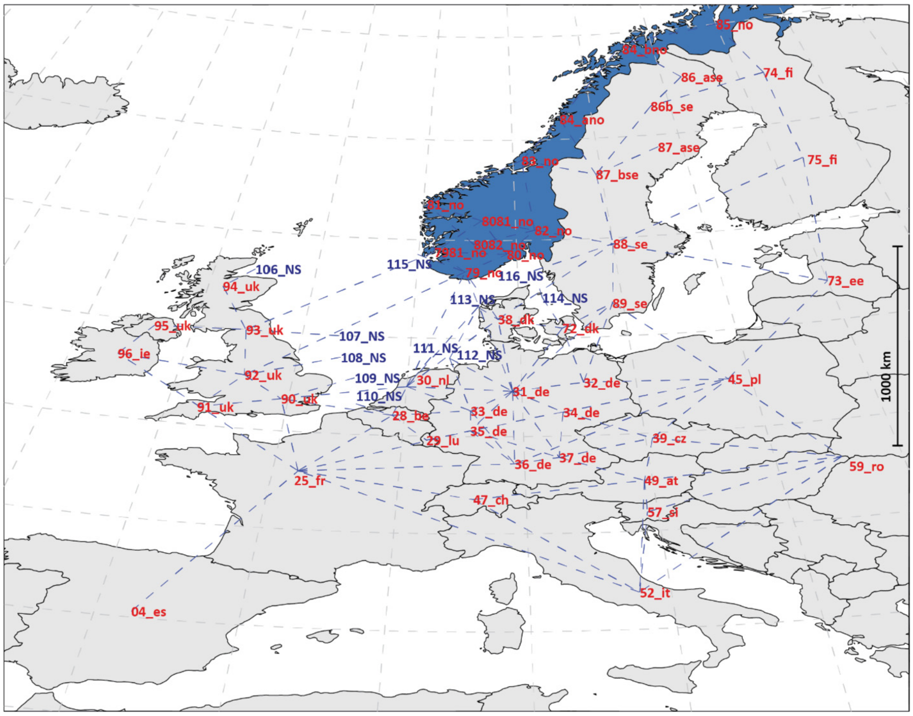

Fig. 3. Illustration of the regional coverage and resolution of the EMPS model, with dotted lines indicating transmission capacity.

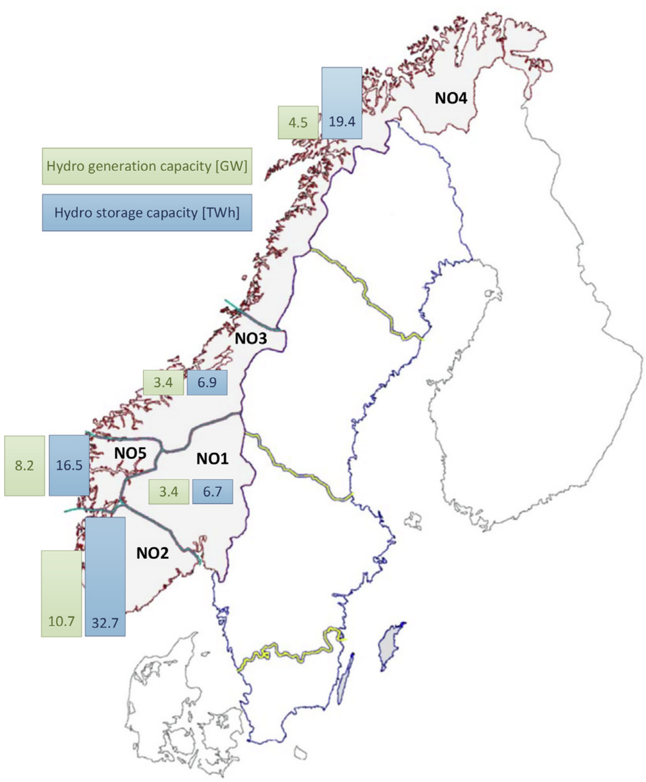

Fig. 4. Map of Norway, divided by price area, indicating hydro generation and storage capacity.

operation with perfect foresight from 2015 to 2050, and EMPS models one static power infrastructure and simulates the operation over multiple weather years. Because of these differences, EMPS and TIMES-Norway have different characteristics with regard to which of the parameters are model input (exogenous) and which are model output (endogenous).

Table 1 gives an overview of the properties of common model parameters in the two models. As opposed to EMPS, TIMES-Norway invests in new capacity and thereby has endogenous evolution of the electricity generation and transmission capacity in Norway. Also, since TIMES-Norway optimises the use of energy carriers to meet the future energy service demand, the electricity demand with sub-annual profile is model output whereas the electricity demand is a model input to EMPS.

Both models optimise the operation of the electricity sector and thereby provide endogenous electricity generation and marginal electricity costs, hereby denoted the electricity price. Note that EMPS provides the short-run marginal cost of electricity, which is the lowest cost to produce one new unit, given fixed transmission and generation capacities, whereas TIMES-Norway provides the long-run marginal cost, which is the lowest cost to produce one new unit if the capacity and electricity demand can be freely set.

Further, the spatial and temporal resolution differ considerably between EMPS and TIMES-Norway. The two models have different sub-annual temporal resolution, with 260 time-slices in TIMES-Norway and 3744 time-slices in EMPS. Moreover, EMPS includes all European countries and TIMES-Norway covers Norway only. This implies that the electricity prices outside Norway are

Table 1
Properties of common model parameters.

Model parameter	EMPS	TIMES-Norway
Electricity generation capacity in Norway	**Exogenous**	Endogenous
Electricity transmission capacity in Norway	**Exogenous**	Endogenous
Electricity demand in Norway	**Exogenous**	Endogenous
Electricity generation in Norway	Endogenous	Endogenous
Electricity prices in Norway	Endogenous	Endogenous
Electricity prices outside Norway	Endogenous	**Exogenous**

exogenous in TIMES-Norway, whereas these prices are endogenous in EMPS. Another important difference between the models is the representation of weather-dependent parameters related to renewable generation and temperature-dependent demand: EMPS uses 30 weather years in the water value calculation, whereas TIMES-Norway provides investments based on one deterministic future.

In the linking strategy, exogenous parameters in one model are replaced with endogenous parameters from the other model to provide results that are based on a consistent model input. Further, the convergence criterion is based on parameters that are endogenous in both models.

2.4. Linking strategy

The primary goal of linking TIMES-Norway and EMPS is to improve the decision support provided by each of these models. For TIMES-Norway, the linkage is designed to improve the electricity trade between Norway and external electricity markets, as well as the operational hydropower constraints. For EMPS, the primary motivation for the linkage is that the methodology will provide a consistent set of data related to Norwegian generation capacity, transmission capacity and power demand of the future power sector.

Harmonisation of the model input and structure is the initial step of the linking strategy. First, the 11 Norwegian regions of EMPS are mapped to the five regions of TIMES-Norway. Second, the existing electricity generation capacities, efficiencies and transmission capacities are harmonised for each of the five regions. Both models use the New Policies in World Energy Outlook 2017 [35] as a basis for future fossil energy prices.

Fig. 5 illustrates one iteration of the linking between the TIMES-Norway energy system model and the EMPS power market model. In this paper, the linkage is executed for the years 2030 and 2050 and for each of the five Norwegian spot price areas. First, the linking uses electricity trade prices and operational hydropower constraints from EMPS as an input to TIMES-Norway. In this instance, trade prices include prices in countries with transmission capacity to Norway, namely Finland, the United Kingdom, Germany, the Netherlands, Denmark and Sweden. The hydropower constraints are represented by a weekly availability factor for hydropower generation, where the availability factor is defined as the expected generation over the maximum theoretical generation given the installed capacity. Note that there is an exemption for the initial first linkage iteration, hereby denoted *L1*, where the TIMES-Norway model does not include any input from EMPS.

Second, the linking uses the transmission capacity, electricity generation capacity and electricity consumption from TIMES-Norway as an input to EMPS. Here, the electricity generation capacity is split by type, including wind power, hydropower, photovoltaic power (PV) and combined heat and power (CHP). The transmission capacity includes both internal capacity within Norway and capacity to external countries. The electricity consumption includes demand for each sub-annual time slice.

Third, the corresponding convergence of the TIMES-Norway and EMPS model results is tested. In this paper, the difference in hydropower income between the two models is used as a test for convergence. This is motivated by the electricity generation mix in Norway which is dominated by hydropower and the fact that the strength of EMPS is the modelling of the Norwegian hydropower system. For each model, the hydro income is the sum of the endogenous electricity price multiplied by the endogenous electricity generation per time slice. For EMPS, the expected income, using the electricity prices and generation of all simulated weather years, is used to test for convergence. The hydropower income as a convergence criterion gives a convergence of generation and electricity prices, both of which are important. The generation ensures that the energy balance is similar between the two models, and the prices considers that the investments in the energy system model have the same price assumptions as the power market model.

In this paper, five iterations of the linking procedure are executed to evaluate how the convergence criterion changes with the number of iterations. In an applied setting, the iterations between the models can be stopped when the difference in hydropower income is lower than a user defined limit. However, if the convergence criterion is not satisfied, the iteration is continued according to the described linking procedure.

The exchanged data are adjusted since EMPS is solved for 30 weather years and has a finer temporal and spatial resolution than TIMES-Norway. Expected weather values from EMPS over the 30 simulated weather years are used from EMPS. To adjust for differences in temporal resolution, the electricity trade prices from EMPS are aggregated to the coarser time-slice resolution of TIMES-Norway, and the electricity consumption data from TIMES-Norway are disaggregated to the finer spatial resolution of EMPS based on consumption statistics from 2015.

3. Results

This section presents the analysis instances used to demonstrate the proposed linkage strategy and shows selected model results of executed linkage for hydropower income, EMPS electricity prices and TIMES model results.

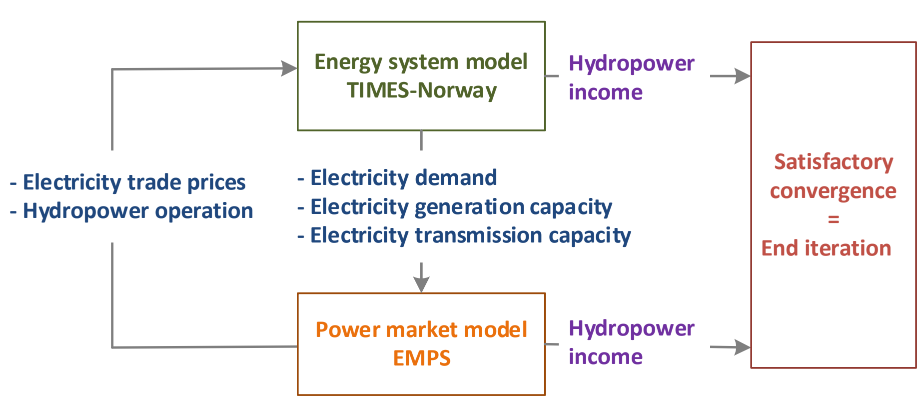

Fig. 5. Illustration of the bidirectional linking methodology.

3.1. Scenarios

The proposed linking methodology is demonstrated for two scenarios and two analysis years, 2030 and 2050, giving four analysis instances. The scenarios differ in their assumptions on the future evolution of the power market in European countries outside Norway. The first scenario, **Fixed (*FIX*)**, assumes that the power market development in Europe (outside of Norway) is static and has the same electricity generation capacity, generation and consumption in 2030 and 2050 as in 2015. The second scenario, **Renewable (*RNW*)**, assumes a highly decarbonised energy system in 2030 and 2050 that are based on and further developed from e-Highways2050 [32].[1]

A comparison between the two scenarios for selected power market assumptions for Germany, the United Kingdom and Sweden, which are countries with transmission capacity to Norway, are illustrated in Table 2. The numbers illustrate that both the electricity demand and intermittent electricity generation is higher in *RNW* than *FIX*. The presented electricity demand is the initial EMPS input on electricity demand. The electricity demand is 1%, 12% and 10% higher in 2030 and 18%, 39% and 21% in 2050 for *RNW* than *FIX* for Germany, the United Kingdom and Sweden respectively. Further, in 2050 the sum of PV and wind generation is 3, 11, and 7 times higher in *RNW* than *FIX* for and the respective countries. Among the selected countries, Germany and the United Kingdom have the highest share of intermittent generation of the total electricity generation in *RNW*, with 79% in 2050.

3.2. Hydropower income and generation

Fig. 6 shows the hydropower income for each analysis instance from TIMES-Norway and EMPS over five model iterations, hereafter denoted *L1* to *L5*. Fig. 6 illustrates two characteristics of the linkage strategy. A first observation is that there are only minor changes in income in both models from iteration number two, *L2*, to iteration number five, *L5*. A second observation is that the proposed linking strategy converges for three of the four instances; for the Fixed scenario, *FIX*, in both 2030 and 2050 whereas the Renewable scenario, *RNW*, only converges for 2030. Note that for this study, the numbers of iterations are limited to five since the model parameters are only marginally changed from the fourth to the fifth iteration. Nevertheless, this does not guarantee that differences in hydropower income between the two models will be the same for further iterations.

For the Renewable scenario, *RNW*, the models only converge in 2030, where the difference in income is 118%, −13% and 2% for iterations *L1*, *L2* and *L5* respectively. For *RNW* in 2050, however, there is no convergence since the hydropower income is significantly higher for the energy system model than for the power market model for all iterations. For example, for the fifth iteration, *L5*, the income is 6091 million euro for TIMES-Norway and 2829 million euro for EMPS. The divergence is relatively stable from the second iteration, with 96% and 115% higher income in TIMES-Norway than in EMPS for *L2* and *L5* respectively. Consequently, for *RNW* in 2050 the two models give completely different results for the profitability of Norwegian hydropower as a part of a European power market with a high share of renewables.

For all four instances, the hydropower generation is relatively stable from iteration two, *L2*, to iteration five, *L5*, but is slightly lower in TIMES-Norway than in EMPS. For *L5*, the deviation in hydropower generation is 2% and 3% in 2030, and 3% and 3% in 2050, for *RNW* and FIX respectively. The lower generation in the TIMES-Norway energy system model indicates that the hydropower constraints, derived from expected hydropower operation from 30 weather years in EMPS, are too strict to give the same expected generation in the two models. This can be related to the approach used to adapt the spatial and temporal differences between the two models.

For *RNW* in 2050, the lower income in EMPS is due to the fact that the endogenous electricity prices are significantly lower in EMPS than in TIMES-Norway. This demonstrates that there are fundamental differences between the two models in terms of how electricity prices are set in Norway with a high share of intermittent electricity generation. The results can indicate that the power market model, where the income of the producers is set by the difference in clearing price and short-run marginal costs, is not able to recover their investment and operational expenses in a highly renewable scenario. Note that the study represents the day-ahead market only, whereas the income of producers can also be covered by ancillary services market.

3.3. Electricity prices from the power market model

To illustrate the differences between the power market characteristics in the two scenarios, the electricity price from EMPS for Germany in 2050 for L5 are plotted for *FIX* and *RNW* in Figs. 7 and 8 respectively. The corresponding figures of the German electricity price for 2030 are included in Appendix A.

The daily electricity price profiles for 30 weather years are plotted for winter (December, January and February), spring (March, April, May), summer (June, July and August) and fall (September, October, November). Note that to better illustrate the electricity price characteristics, the y-axis is different in Figs. 7 and 8, and the plots are limited to the 10th and 90th percentiles. These

Table 2
Model assumptions on electricity demand and generation in Germany, the United Kingdom and Sweden for two future scenarios, Fixed (FIX) and Renewable (RNW) in 2030 and 2050.

	Country/scenario Model period	FIX 2030 and 2050	RNW 2030	RNW 2050
Electricity demand [TWh]	Germany	591	598	700
	United Kingdom	333	372	462
	Sweden	136	149	165
PV and wind generation [TWh]	Germany	121 (19% of total generation)	298 (57% of total generation)	416 (79% of total generation)
	United Kingdom	34 (11% of total generation)	233 (62% of total generation)	382 (79% of total generation)
	Sweden	11 (8% of total generation)	50 (41% of total generation)	80 (56% of total generation)

[1] https://docs.entsoe.eu/baltic-conf/bites/www.e-highway2050.eu/results/.

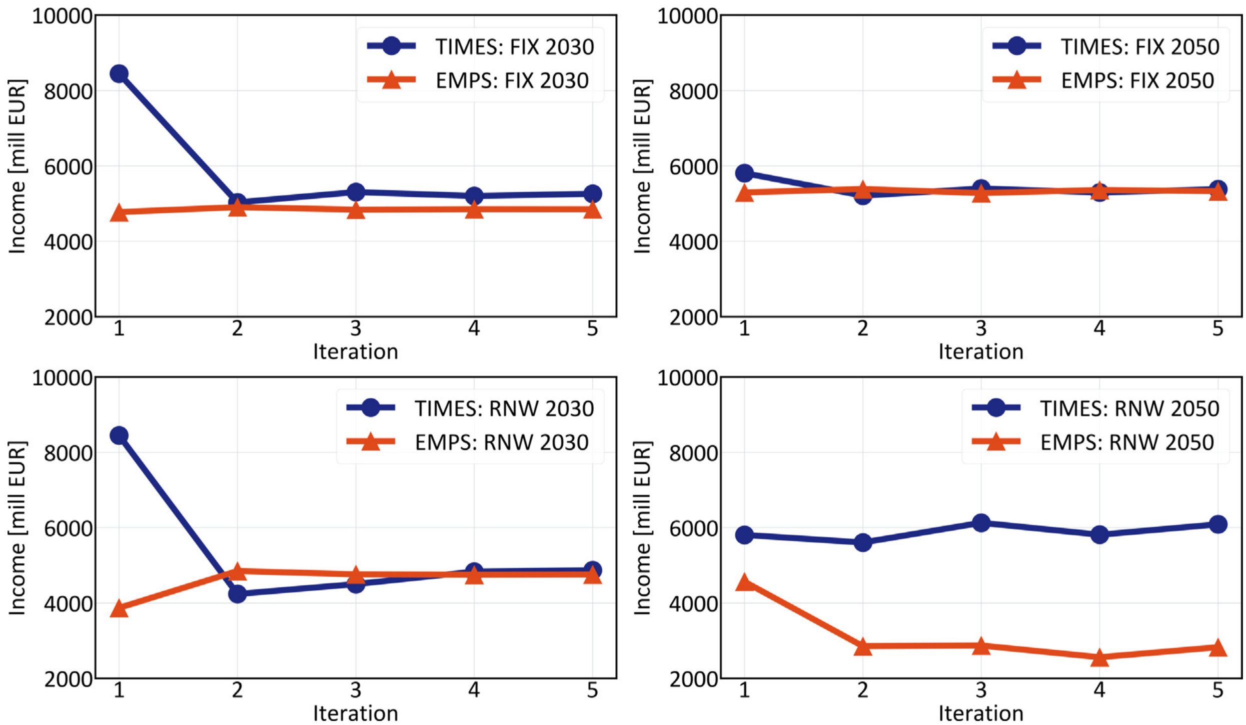

Fig. 6. Hydropower income from TIMES-Norway and EMPS for five model iterations and for the FIX scenario (upper) and RNW scenario (lower) in 2030 (left) and 2050 (right). Note that the difference in hydro income of the first iteration, *L1*, depends largely on the initial TIMES-Norway assumptions regarding the electricity prices in countries with transmission capacity to Norway. For the Fixed scenario, *FIX*, assuming 2015 power market characteristics, the convergence criterion on hydropower income, defined as the difference in income between the two models, is considerably improved after the second iteration. The difference in hydropower income between TIMES and EMPS is 77%, 3% and 8% in 2030 and 10%, −3% and 1% in 2050 for iterations *L1*, *L2* and *L5* respectively.

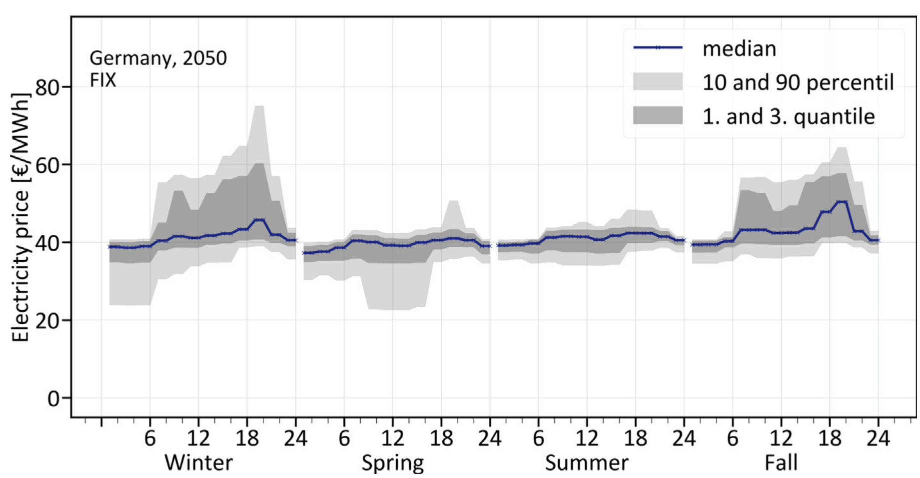

Fig. 7. EMPS daily electricity price characteristics of Germany for FIX in 2050 for 30 weather years (1981–2010).

figures demonstrate that the variability of the electricity price is significantly higher for *RNW* in 2050 than for the other analysis instances, both between the weather scenarios and between the hours of the day. For example, for summer in 2050, the hourly median price ranges from 39 EUR/MWh at 01:00 to 42 EUR/MWh at 17:00 for *FIX*, and from 0 EUR/MWh at 13:00 to 145 EUR/MWh at 21:00 for *RNW*. The daily price variation for *RNW*, both in 2030 and 2050, shows that electricity prices are lowered in the middle of the day in the presence of PV and are higher in the evening and at night. Further, the deviations in electricity price within 1 h are significantly higher for *RNW* in 2050 than the other instances. For example, in winter 2050 at 24:00, the electricity price ranges from 19 EUR/MWh to 57 EUR/MWh for *FIX* (36 EUR/MWh to 44 EUR/MWh for the 10-90th percentile) and between 0 EUR/MWh and 294 EUR/MWh for *RNW* (10 EUR/MWh to 208 EUR/MWh for the 10-90th percentile). The results show similar electricity price characteristics for the other countries that have electricity trade with Norway.

For *RNW* in 2050, the average annual hydropower sales price, derived by dividing the hydropower income by generation, is significantly different between EMPS and TIMES-Norway. The annual sales price is 45 EUR/MWh for TIMES-Norway and 18 EUR/MWh for EMPS for iteration five, *L5*. Consequently, the higher electricity price of TIMES-Norway gives significantly higher

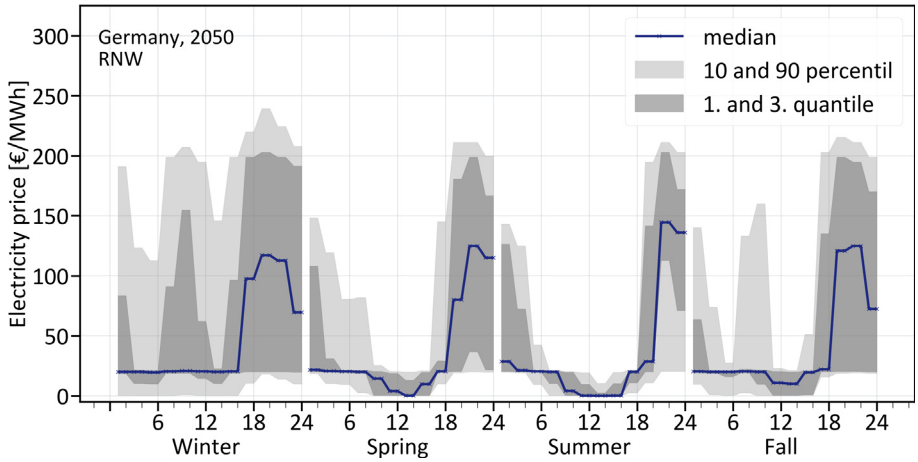

Fig. 8. EMPS daily electricity price characteristics of Germany for RNW in 2050 for 30 weather years (1981–2010).

investments in new generation technology compared to what is profitable from an EMPS perspective. The 2050 EMPS electricity price in the Norwegian spot price area NO3, given the fixed input from TIMES-Norway, is shown for *FIX* and *RNW* in Fig. 9 and Fig. 10 respectively. The corresponding figures for the NO3 electricity price for 2030 are included in Appendix A. For the instance with divergence, *RNW in 2050*, the expected electricity price in NO3 is 14 EUR/MWh. This is significantly lower than the levelised cost of electricity (LCOE) from wind power, derived from the model input to TIMES-Norway in NO3, which ranges from 29 to 37 EUR/MWh in 2050. This indicates that, for this instance, the wind power investments in TIMES-Norway are not compatible with the electricity prices generated from EMPS. However, this is different for the other instances for example the expected electricity price for *FIX* in 2050 of 38 EUR/MWh.

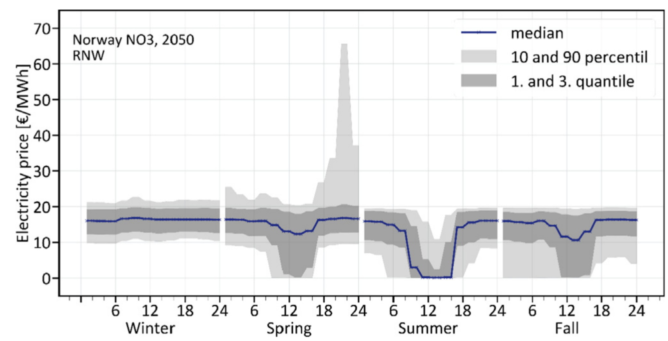

Fig. 10. EMPS daily electricity price characteristics of NO3 in Norway for RNW in 2050 for 30 weather years (1981–2010).

3.4. Energy system model results

Both the electricity generation capacity and the electricity trade, endogenously set by TIMES-Norway, are significantly affected by the linkage iterations. Fig. 11 shows the electricity generation capacity in 2050 for both scenarios and for the five iterations. Among the electricity generation technologies, wind power capacity is most sensitive to the linkage iteration and type of scenario. Note that the PV capacity is equal for all the iterations and scenarios since it is exogenously set in both models. The Norwegian wind power capacity is highest in a renewable transition of the European power market and is 3.6 GW and 12.0 GW in iteration 5, *L5*, for *FIX* and RNW respectively. For both scenarios, the annual electricity consumption in 2050 varies less than 2% between the five iterations. It is therefore primarily electricity trade that is affected by the differences in electricity generation capacity. The corresponding Norwegian net electricity trades in 2050 are shown in Fig. 12. For

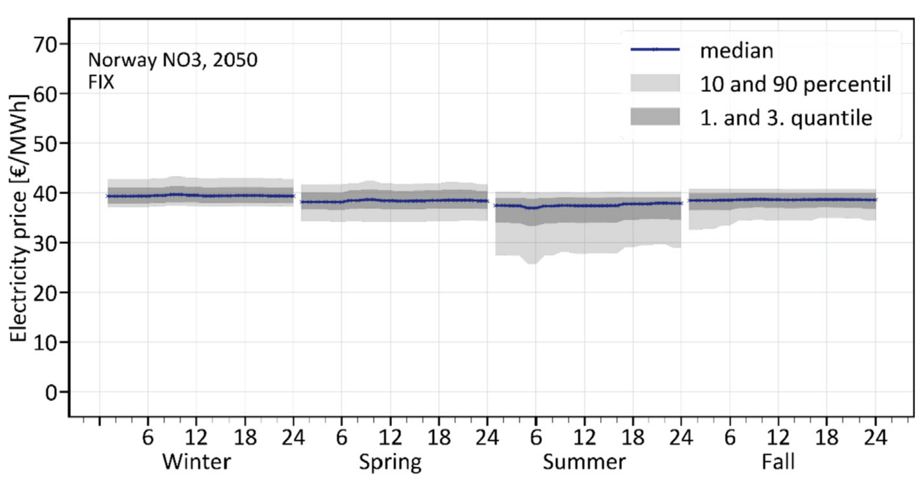

Fig. 9. EMPS daily electricity price characteristics of NO3 in Norway for FIX in 2050 for 30 weather years (1981–2010).

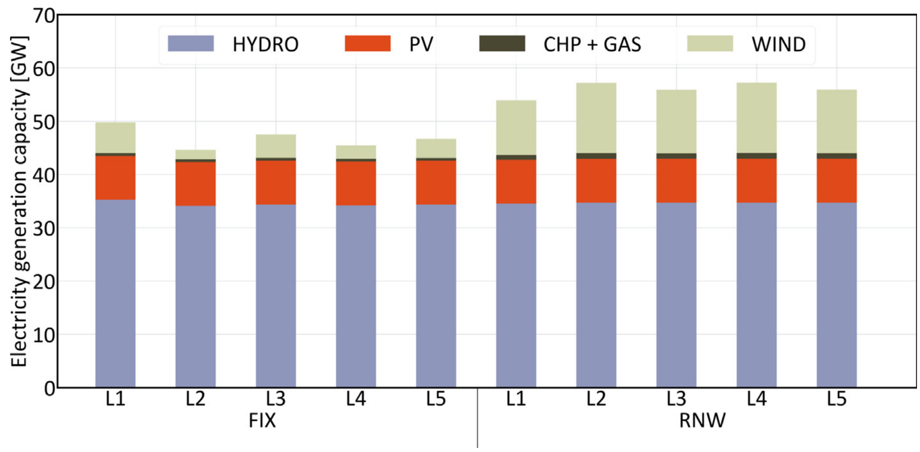

Fig. 11. TIMES-Norway electricity generation capacity in 2050 for five model iterations in FIX and RNW.

FIX, the net electricity export is reduced from 19 TWh in the first iteration, *L1*, to 3 TWh in the last iteration, *L5*. Similarly, for *RNW*, the net electricity export ranges from 19 TWh in *L1* to 31 TWh in *L5*.

It is both the electricity trade prices and hydropower constraints from EMPS that cause different TIMES-Norway results by linkage iterations. Fig. 13 illustrates how the hydropower generation in TIMES-Norway changes with the linkage by showing the weekly generation for *FIX* in 2050 for the first linkage iteration, *L1*, and the fifth linkage iteration, *L5*. The electricity generation in TIMES-Norway is higher in winter weeks and lower in summer weeks in *L1* compared to *L5*. This can indicate that the initial method of modelling hydropower generation in TIMES-Norway, based on a more aggregated modelling approach, is more flexible than the EMPS model with a detailed description of Norwegian hydropower.

4. Conclusions and discussion

This paper proposes and demonstrates a novel bidirectional linkage strategy between the EMPS power market model and the TIMES-Norway energy system model. The aim of the linkage is to provide long-term investment strategies for the energy system that explicitly consider the complexity of the power sector. The linkage is executed for two scenarios, with different assumptions concerning the development of the power market in European countries outside Norway in both 2030 and 2050, giving four analysis instances. The first scenario, *FIX*, assumes the European power system is fixed as in 2015 until 2050. The second scenario, *RNW*, assumes a transition to a low-carbon power market, with a significant share of intermittent renewables and increased electricity demand towards 2050 compared to 2015.

The proposed linkage methodology of this paper demonstrates that it is valuable to use power market models and energy system models in combination to analyse the future energy system. The energy system model provides a consistent set of model input data on electricity generation capacity, transmission capacity and consumption to the power market model. Further, corresponding constraints on hydropower operation and electricity exchange prices from the power market model are used as an input to the energy system model to ensure a realistic representation of the power market. In this paper, the Norwegian hydropower income is used as a convergence criterion since Norwegian electricity generation is primarily hydropower and because the energy system model, from a computational perspective, is not able to directly incorporate a detailed description of Norwegian hydropower. The linkage strategy is successful when the development of the European power market does not deviate significantly from the current market structure. However, for the Renewable scenario, *RNW*, in 2050, with large variations in electricity price and a high share of intermittent electricity supply, the linking strategy fails to converge on hydropower income. This underlines the importance of testing a linking strategy for various model assumptions if it is intended as a general methodology.

The convergence criterion is met for three of the four analysed instances. There is a divergence for the highly renewable instance

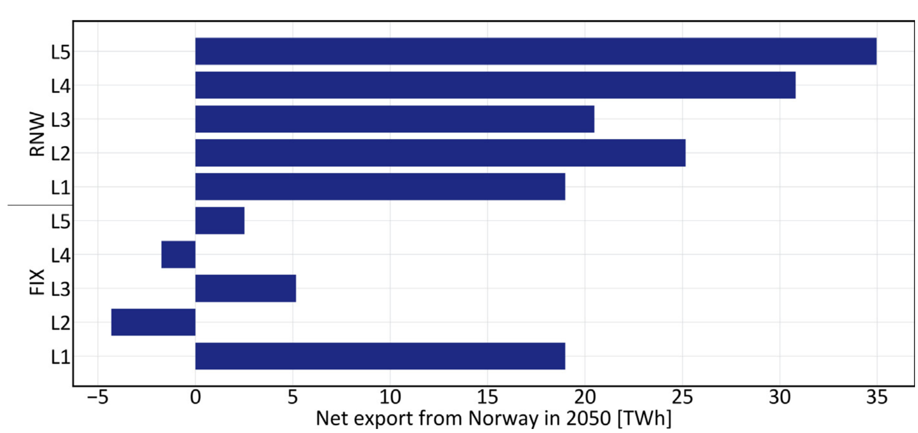

Fig. 12. Net Norwegian electricity export in for FIX and RNW in 2050 for five linkage iterations.

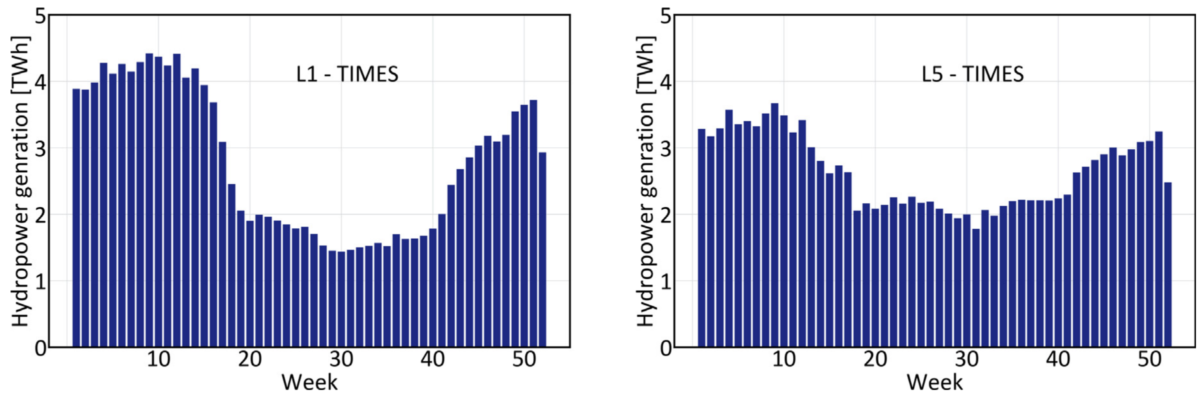

Fig. 13. Weekly hydropower generation in 2050 for FIX in TIMES-Norway for L1 and L5.

because the simulated Norwegian electricity price for this situation differs significantly between the two models. The divergence exists even though the two models' input data is harmonised and power market capacities and consumption are aligned through linkage. There can be several reasons the convergence is distorted in a scenario with a high share of renewables. The results indicate that one reason can be that the day-ahead market does not provide enough income to the power producers to cover their expenses in a highly renewable scenario. Further, the divergence can be related to weaknesses of each of the models or be caused by the linkage methodology itself. Further research is needed to understand these mechanisms and thus be able to design a more robust linking strategy. Nevertheless, it will require insights from both energy system models, with a detailed description of end-use by sector, and power sector models, with a detailed representation of the power market, to find a solution.

When the linkage is successful, the results show that the convergence criterion on hydropower income is considerably improved and relatively stable from the second iteration. Consequently, for these instances, a limited computational effort is required to improve the quality of the results of the energy system and power market model by applying the linking strategy. Among the decision variables in the TIMES-Norway energy system model, it is primarily investments in wind power and Norwegian cross-border trade of electricity that are affected by the model linkage whereas the electricity consumption is relatively stable between model iterations. For example, in 2050 for *FIX*, the wind power capacity is 5.8 GW initially and 3.6 GW in the fifth iteration, *L5*, whereas the net electricity export changes from 9 TWh initially to 1 TWh in *L5*. Besides improving the quality of the model results from TIMES-Norway, the linkage provides results that are not traditionally provided by long-term energy system models. The EMPS results provide weather-robust decision support for the given capacity and demand from TIMES-Norway by giving the operation of the Norwegian power market for 30 different weather years.

Declaration of competing interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

CRediT authorship contribution statement

Pernille Seljom: Conceptualization, Methodology, Formal analysis, Writing - original draft, Writing - review & editing, Visualization. **Eva Rosenberg:** Conceptualization, Methodology, Software, Investigation, Formal analysis, Writing - original draft, Visualization. **Linn Emelie Schäffer:** Conceptualization, Methodology, Software, Investigation, Formal analysis, Writing - original draft, Visualization. **Marte Fodstad:** Conceptualization, Supervision.

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Appendix A

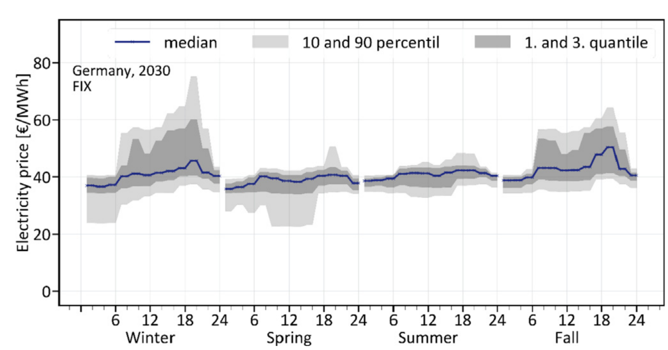

Fig. A1. EMPS daily electricity price characteristics of Germany for *FIX* in 2030 for 30 weather years (1981–2010).

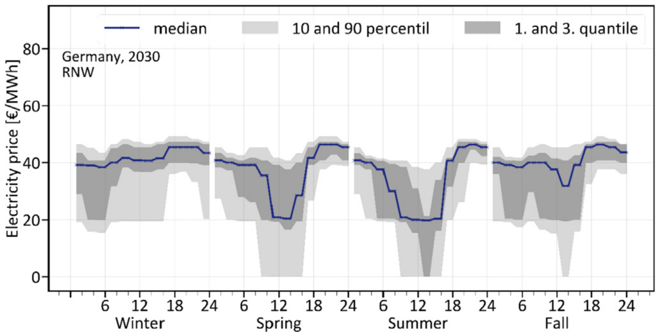

Fig. A2. EMPS daily electricity price characteristics of Germany for *RNW* in 2030 for 30 weather years (1981–2010).

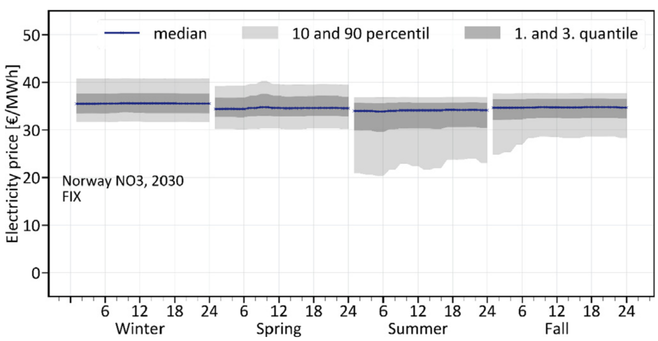

Fig. A3. EMPS daily electricity price characteristics of NO3 in Norway for *FIX* in 2030 for 30 weather years (1981–2010).

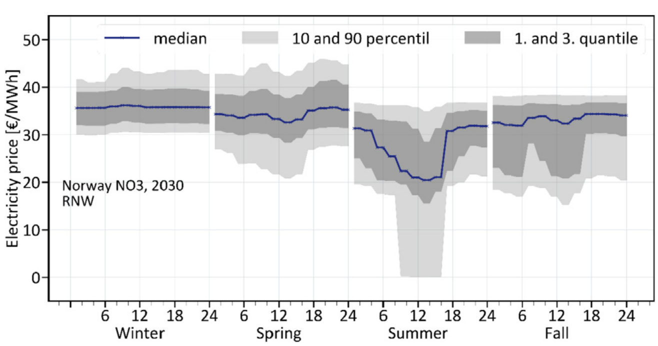

Fig. A4. EMPS daily electricity price characteristics of NO3 in Norway for *RNW* in 2050 for 30 weather years (1981–2010).

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